Int J Life Cycle Assess (2014) 19:677–687
DOI 10.1007/s11367-013-0651-8

Life cycle consumptive water use for oil shale development and implications for water supply in the Colorado River Basin

Aweewan Mangmeechai · Paulina Jaramillo · W. Michael Griffin · H. Scott Matthews

Received: 21 February 2013 / Accepted: 2 September 2013 / Published online: 18 September 2013

Abstract
Purpose Oil shale is an unconventional petroleum source that can be produced domestically in the USA. Oil shale resources are primarily located in Utah, Wyoming, and Colorado, within the Colorado River Basin. In this paper, we analyze the life cycle consumptive water use for oil shale production and its impacts on water resources of the Colorado River Basin.
Methods The study is focused on life cycle consumptive water use for oil shale development. Consumptive water use is defined as "water that is evaporated, transpired, incorporated into products, or otherwise removed from the immediate water environment." The analysis includes direct consumptive water requirements to extract, process, and refine shale oil, as well as indirect consumptive water use for generating the electricity associated with the extraction and processing. From the results, strategies for water supply certainty are discussed, and strategies for implementation are suggested. In addition, refining the shale oil outside of the oil shale region (removing the need for local water), using dry cooling systems for electricity generation, and building desalination plants in California (to replace water) are evaluated.
Results and discussion Life cycle consumptive water use for oil shale is significant and could impact water availability for consumers in the lower Colorado River Basin. At a level of oil production of 2 million barrels per day, the life cycle consumptive water use would be significant: between 140 and 305 billion gallons (0.4 and 0.9 million acre-ft.) of water per year if surface mining and retorting is done, or between 150 and 340 billion gallons (0.5 and 1 million acre-ft.) of water per year if the Shell in situ process is used. Strategies could be implemented to provide water supply certainty including refining the shale oil outside of the region (removing some need for local water), using dry cooling systems for electricity generation, and building desalination plants in California (to replace water).
Conclusions Water supply in the Colorado River Basin could be a primary constraint to the development of oil shale. At a level of oil production of 2 million barrels per day, the life cycle consumptive water use would be significant. Energy companies or governments may want to invest in water management and supply strategies that would eliminate the uncertainty associated with the water availability in the Colorado River Basin for oil shale development.

Keywords Life cycle consumptive water use · Oil shale · Water footprint

Abbreviations

Bpd	Barrels of oil per day
gals/bble	Gallons of water per barrel of oil equivalent
kWh	Kilowatts hour
lb CO_2e/bble	Pounds of CO_2 equivalent per barrel of oil equivalent

Responsible editor: Stephan Pfister

A. Mangmeechai (✉)
International College of National Institute of Development Administration, Bangkok 10240, Thailand
e-mail: aweewan.m@nida.ac.th

H. S. Matthews
Civil and Environmental Engineering Department, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213-3890, USA

P. Jaramillo · W. M. Griffin · H. S. Matthews
Department of Engineering and Public Policy, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213-3890, USA

W. M. Griffin
Tepper School of Business, Carnegie Mellon University, 5000 Forbes Avenue, Pittsburgh, PA 15213-3890, USA

1 Introduction

The USA consumed 18.5 million bpd in 2012 (DOE 2013a, b). Of this, 10.6 million bpd were imported as crude oil and petroleum products, while 7.9 million bpd of crude oil was produced domestically (DOE 2013a, b). While the gap between production and consumption has decreased in recent years, there is still substantial interest in exploring and developing alternatives to conventional oil to enhance markets and provide energy security. Canadian oil sands have been the focus of recent discussions about the environmental impacts of unconventional oil resources. However, with the uncertainty associated with the construction of the Keystone XL pipeline that would deliver oil from the Alberta oil sands to the USA, there may be continued interest in exploring domestic unconventional oil resources such as oil shale.

Oil shale is a mixture of organic compounds in a mineral matrix. The shale has between 10 % and 20 % organic matter of which 75 % is kerogen (Göklen et al. 1984), a solid, insoluble, organic material. Others have reported larger ranges, 5 % to 40 % kerogen by weight (Hendrickson 1975). The minerals are a mixture of carbonates (dolomite and calcite) and silicates (quartz and potassium aluminum silicate). The quality of oil shale is measured as the gallons of oil produced per ton of shale. Green River shale, which is the focus of this paper, ranges from 20 to 40 US gallons per short ton. Smith (1961) found that the kerogen fraction had a composition of $C_{215}H_{330}O_{12}N_5S$, with a C/H ratio of 1.5. More recent analyses have demonstrated C/H ratios closer to 7, which is similar to the ratios found for petroleum and lower than those for coal. The oil is relatively high in paraffins. Thus, with upgrading, it becomes an excellent refinery feedstock. Depending on the upgrading process, the resulting shale oil has a gravity of 20° to 38° API. The high hydrogen content results in a refinery feedstock that has high yield of diesel and jet fuel when refined (DOE 2004a). Green River Shale is considered a dry shale having a water content of 1–1.5 %.

The US Geological Survey has recently updated its resource estimates suggesting that there is a total of 4.3 trillion barrels of oil in-place in the three principal basins of the Eocene Green River Formation (USGS 2013), higher than the previous estimate of 2.8 trillion barrels (Bartis et al. 2005; Andrews 2008). Between 353 and 1,146 billion barrels of the in-place resource have a high potential for development. Of these, 352–920 billion barrels are located at Piceance Basin, 1.3–93.6 billion barrels are located at Unita Basin, and 133 billion barrels are located at Greater Green River Basin (USGS 2013).

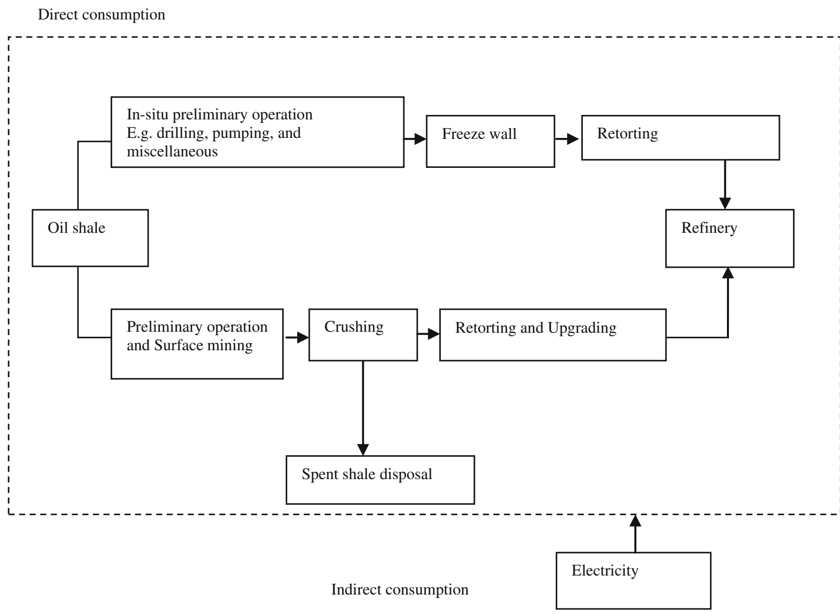
Shale oil can supplement domestic conventional oil production and may become a crucial part of the mix of US future fuels (Williams 2003). Shale oil is not produced at commercial scale but has been produced in Australia and Estonia in the past (Smith 2005). The idea of extracting US oil shale is not new. In the early 1970s and 1980s, many in government and industry were promoting the rapid buildup of an oil shale industry, but most of the projects were later canceled due to technical difficulties and decreasing crude oil prices (Bartis et al. 2005).

There are, however, current RD&D pilot projects at the oil shale basin like Enefit's Utah Project, American Shale Oil, and Shell ICP (NOSA 2013).

Shale oil can be produced through surface mining or in situ production methods. For surface mining, oil shale is mined and crushed, and the kerogen is retorted. Numerous surface retorting approaches have been tested at pilot and semi-commercial scales. Two major promising types of surface retorts are vertical and horizontal retorts. Vertical retorts (e.g., Petro-Six and Paraho technology) are currently being considered for a major non-US oil shale development effort. The TOSCO II and the Alberta Taciuk Processor (ATP) use horizontal rotating kilns for pyrolysis. The Alberta Taciuk Processor (ATP) retort process has been identified as the process of choice for surface mining production of oil shale (Brandt 2009) and is the surface mining method analyzed in this paper. The ATP retort is a rotating horizontal kiln with four main zones: preheat, retort, combustion, and cooldown. Shale enters the retort where it is heated initially to 250 °C in the preheat zone and finally to 500 °C (max 600 °C) for the retort. Higher temperatures are achieved in the combustion zone to remove char from the spent shale, and this heat is used in the process (Brandt 2007). The advantages of ATP are (1) simple and robust design, (2) energy self-sufficiency, (3) ability to handle fine particles (US oil shale), (4) high oil yields (Johnson et al. 2004), energy use conservation by using the char from spent shale minimizing natural gas use, and (5) has low water requirements, important in this analysis (Brandt 2007).

For in situ oil shale production, the shale is left in place and retorted underground. There are three types of in situ processes: True in situ, Modified in situ, and Shell ICP. In the True in situ process, the shale is fractured and air is injected. The shale is then ignited to heat the formation so that the oil can flow through the fractures and into wells. True in situ processes have difficulties in controlling the flame front, which can leave areas unheated and limit oil recovery. In the modified in situ process, voids are mined above or below the formation. The shale is then ignited to heat designated areas, and liquids are recovered from below or above the formation. Groundwater contamination is the major challenge for both True and Modified in situ processes. The Shell ICP process is quite novel and has the potential to make much deeper, thicker, and richer resources available for development. In this process, gas or electric heaters are used to heat the shale for a period of up to 4 years, creating micro-fractures in the formation, which in turn improves flow and permeability. The heated shale and gases produced during the heating process are recovered to the surface using conventional well technology. The Shell ICP process could recover larger percentages of the available resource at

Fig. 1 Oil shale process diagram



high quality, in a more economic and environmentally sound manner (DOE 2004b). Shell is currently operating a modest field research effort in northwestern Colorado's Piceance Basin to test ICP's viability on the basin's world-class oil shale reserves (DOE; Shell 2013). Given its potential and the availability of data, the Sell ICP process is the in situ methods analyzed in this paper.

Figure 1 presents a simple schematic of the oil shale production processes. The properties of the oil produced by different retorting processes vary widely, as described previously. For the most part, crude shale oil resembles conventional petroleum, composed primarily of long-chain hydrocarbon molecules with boiling points that span roughly the same range as typical petroleum crudes. However, oil produced from the retort might need to be partially upgraded to meet the qualities required by existing US refineries.

While there are test projects, the current boom in Canadian oil sands has increased the uncertainty associated with the feasibility of large-scale oil shale development. Some still suggest that a 1- to 3-million-barrel-per-day industry may be a realistic scale (Bartis et al. 2005; USGS 2013). However, water use could be a major challenge to commercial scale of oil shale development, and there has been no work to systematically evaluate these challenges. Significant amounts of water are needed to extract and process oil shale. This water is used for dust control, cooling, spent shale reclamation, raw shale oil upgrading, environmental control, and for the various plant operations that support the projects (DOI 2008a, b, c, d). In addition, there are significant upstream water requirements to generate the electricity used for oil shale production. The richest oil shale resources in the USA are located in Colorado, Utah, and Wyoming—within the Colorado River Basin—where water supply is limited. Sufficient local water resources may not be available over the lifetime of the project. Thus, additional water might have to be imported from other sites. For the pilot project currently in operation, the water is transported by trucks to the sites (US DOE 2011). In this paper, we analyze the water supply requirements and constraints for oil shale development (initially assuming that the entire life cycle occurs within the region). We then identify strategies to provide water supply certainty for oil shale development in the Colorado River Basin.

2 Methods

2.1 Life cycle water consumption for oil shale production

Water consumption has recently been included in life cycle assessment studies (Boulay et al. 2011; Emmenegger et al. 2011; Hospido et al. 2013; Tendall et al. 2013; Kounina et al. 2013). There are two terms generally used for measuring water use: consumptive water use and water withdrawal. Consumptive water use is defined as “water that is evaporated, transpired, incorporated into products, consumed by humans, or otherwise removed from the immediate water environment” (USGS 2009). Water withdrawal is defined as water that is used in a process, returned to the environment, and is available for the same or other uses (USGS 2009). In this study, we focus on consumptive water use for oil shale development as such use precludes other uses. Our analysis includes direct consumptive water requirements to extract, process, and refine shale oil, as well indirect consumptive water use for generating the electricity associated with the extraction and processing of the shale oil. Given limitations with data

availability, the analysis presented in this paper is meant to be a bounding analysis that can inform future research.

The US Department of the Interior (DOI 1973) and Gleick (1994) reported that consumptive use for oil shale extraction ranges between 4 and 10 gals of water/bble for surface mining, 97–109 gals/bble for surface retorting and upgrading, and 31–75 gals/bble for in situ production and retorting (DOI 1973; Gleick 1994). Reclamation of the land affected by oil shale extraction activities also requires water. The US DOI (DOI 1973) estimated 65 gals of water/bble are required for spent shale disposal in surface mining. Revegetation of affected lands is estimated to require 6 gals/bble for oil shale surface mining and 12 gals/bble for the oil shale in situ process (DOI 1973). Based on these estimates, on-site consumptive water use for oil shale production is 172–190 gals/bble for surface production and 43 to 87 gals/bble for in situ production.

A more recent study by the Bureau of Land Management's 2008 report about the effects of oil shale development (US DOI 2008a, b, c, d) states that water use for oil shale in situ processes ranges between 42 and 126 gals/bble, while for mining, water use ranges between 109 and 168 gals/bble, slightly higher than those reported by DOI and Gleick (DOI 1973; Gleick 1994; US DOI 1973). After personal communications with representatives at the Bureau of Land of Management, we were able to verify that these are consumptive water use estimates; however, very little detail is provided about the processes included in these estimates. These values, however, have been incorporated in the range of consumptive water use for oil shale production (direct water use). In this study, we thus assume consumptive water use ranges between 109–190 gals/bble for surface mining and 42–126 gals/bble for in situ process.

The retorting process, in general, consumes from 2 to 5 gals of water per ton of kerogen processed. The amount could be as high as 10 gals/ton (DOI 1973). The effluent water has a high organic and solids content. Oil shale production processes require high quality water. Reuse would require treatment such as addition of lime, heating, and contacting with activated carbon and ion exchange resins. Alternatively, the water could be treated to remove volatile components and used to wet spent shale during disposal operations. Wastewater also results from excess mine drainage and retort condensate. Excess mine drainage can be used without treatment as a slurry medium for backfilling burnt out in situ retorts. Alternatively, it must be treated [e.g., reverse osmosis (RO)] before discharging it to surface water or reusing it in the retorting process. It is unlikely that the operators would construct the necessary treatment infrastructure on site. The Green River Basin has already had extensive experience with produced water from natural gas and oil production. It has been reported that most oil and gas operators in this basin use commercial disposal services, owner operated disposal pits, and saltwater disposal wells (Boysen et al. 2002; US DOE 2011).

As previously discussed, some amount of water is produced during the production and retorting process. This wastewater is likely to be disposed of, but some of it could be treated and reused. Information about wastewater treatment can be found at OTA (1980), Kamenev et al. (2003), and Wan (2009). Some estimates suggest that if water is treated on site and reused, an average of 10 % of the direct water required for the oil production process may be saved (NOSA 2012). Developing such a wastewater treatment system could provide process water but would also require additional on-site energy. In addition, water treatment also results in consumptive water use, thus resulting in a water penalty that needs to be accounted for in any analysis. In addition, treated wastewater is not free for the taking. Under Utah's law, all water within the state is public property and administered by the state to maximize benefits to the state's citizens. Water, even wastewater, cannot be used without first obtaining a water right (DOE 2011). Due to the lack of data on water reuse in the production process, and the uncertainty about the availability of such water for energy production, this analysis does not include a detailed estimate of treatment of wastewater for reuse purposes.

A significant amount of electricity is also required for the shale oil retorting processes, and electricity generation has

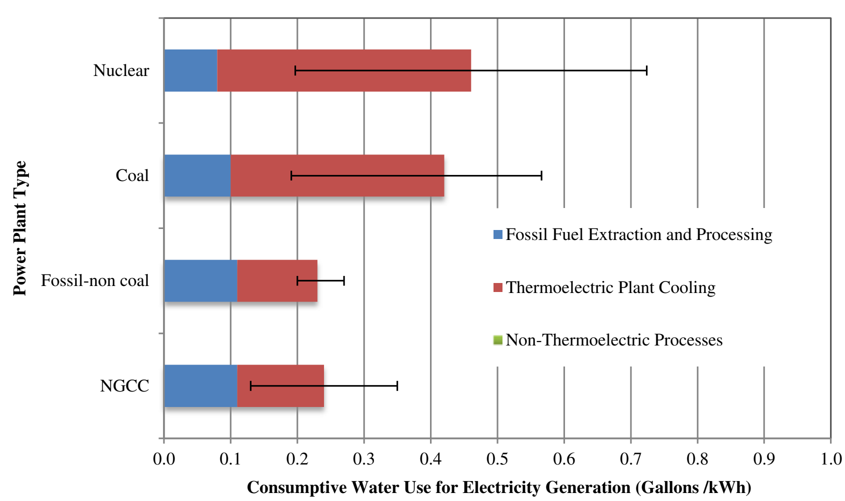


Fig. 2 Consumptive water use for electricity generation [adapted from NETL (DOE 2009)]

significant consumptive water use. Estimates of consumptive water use for power generation were obtained from NETL (DOE 2009). NETL (DOE 2009) reported water consumption for coal, nuclear, natural gas combined cycle (NGCC), and fossil non-coal (primarily oil-based) power generation including the production of the primary fuels and cooling water requirements for thermal plants. Figure 2 shows the estimated consumptive water use for different power plants. The uncertainty bars for the thermoelectric plants result from the ranges reported by NETL.

Brandt (2008, 2009) analyzed energy consumption for shale oil production of the Green River Formation of Colorado, Utah, and Wyoming. Brandt reported low and high energy consumption estimates (hereafter referred to as the low and high energy scenarios) based on two large-scale deployments of the in situ processes and two large-scale deployments of the ATP [surface mining and retorting processes (Brandt 2008, 2009)]. According to Brandt (2009), electricity consumption for surface retorting ranges between 68 and 90 kWh/bble. For the in situ production (freeze wall, retorting, and remediation), electricity consumption ranges between 367 and 400 kWh/bble (Brandt 2008). Brandt reported that some electricity could be generated on-site using hydrocarbon gases produced during the retorting process. For surface mining and retorting, 66 kWh can be generated on site for every barrel of oil shale produced (Brandt 2009). For the in situ process, on-site generation can account for 98 % of the electricity needed in the low-energy scenario and 60 % of the electricity needed in the high-energy scenario (Brandt 2008). Brandt assumed that on-site electricity is generated using a natural gas combined cycle plant with 45 % efficiency. Consumptive water use for this electricity is estimated using the water required for cooling a thermal power plant reported by NETL (DOE 2009): 0.24 gals/kWh (in a plant with a recirculation system).

Additional electricity must be purchased from the grid. The average fuel mix for electricity generated in Colorado in 2011 was 64 % coal, 20 % natural gas, and 14 % renewables. In the low energy consumption case, electricity imports are provided by combined cycle natural gas turbines with 45 % efficiency (Brandt 2008, 2009). Using the data presented in Fig. 2, the water consumption for imported electricity ranges between 0.24 and 0.42 gals/kWh. New power plants will likely need to be constructed to meet increased electricity demand associated with oil shale development. We assume, however, that these new power plants will be thermal power plants (coal or natural gas) with the same water requirements as current thermal plants.

Finally, water is also needed to refine the oil shale into liquid fuels. Western Canada has shown that conventional refineries can be used to refine unconventional crude. There, nine refineries with a total capacity of 628,000 bbl/d blend crude oil with up to 39 % synthetic crude oil and a further 3 % to meet the product requirements of the existing refineries (Energy Resources Conservation Board 2010). Raw shale oil from the retort requires upgrading to stabilize and improve its quality before refining. For this base-case, it is assumed that the oil would be sent to existing refineries where it would be blended to meet the specific processing requirement. Consumptive water use for refining depends on the specific refinery's unit operations. Consumptive water use in traditional oil refining ranges between 27 and 119 gals/bble (Gleick 1994), which is lost mainly in evaporative cooling and in boiler feed water. Changes in fuel formulations and improvements in techniques for restructuring organic molecules have increased water requirements. Consumptive water use in a refinery with reforming and hydrogenation ranges between 76 and 214 gals/bble (Gleick 1994). According to refining capacity data, roughly 89 % of US refineries have hydrotreating processes (DOE 2012). As a result, the weighted-average consumptive water use for US refineries ranges between 70 and 200 gals/bble.

3 Results

Figure 3 shows the per barrel consumptive water use for the production of oil shale. The error bars in the figure represent the variability in the consumptive water use estimates for all life cycle stages. The variability in consumptive water associated with the energy used resulting from different energy use in the low- and high-energy scenarios from Brandt (2008, 2009) is also captured in the error bars. The figure shows separate estimates for the cases when 66–98 % of electricity is generated on-site and the consumptive water use if all the electricity required for retorting were purchased from the grid. The consumptive water use for electricity generation (indirect water use) accounts for 7–9 % of the total water consumption for surface mining and 34–40 % for in situ. The case where all electricity is purchased is shown as a point of reference only. The process produces fuels that can be used to generate electricity on site, and this would likely be done. Given the assumptions about the generation of purchased electricity, there is not much difference in the water use between the estimates for the cases where electricity is generated on-site or purchased from the grid. The rest of the results presented here assume a fraction of the electricity is produced on-site. As can be seen in Fig. 3, for surface mining, consumptive water use for mining, retorting, and processing dominate the other stages, e.g., refining and electricity generation. For the in situ process, water for electricity generation is dominant.

Wu et al. (2009) evaluate the life cycle consumptive water use for refined petroleum products derived for US conventional crude oil and Saudi Arabia crude oil. They found that for US crude, the life cycle consumptive water use is on average 260 gallons of water per barrel of oil (175 and 345 gals/bbl). For Saudi crude, they found an average of 223 gallons of water per barrel of oil (145 to 300 gals/bbl). This is in contrast with our results of 305 gallons of water per barrel for surface mining methods (195–415 gals/bbl) and 325 gallons of water per barrel for in situ production (200 to 450 gals/bbl).

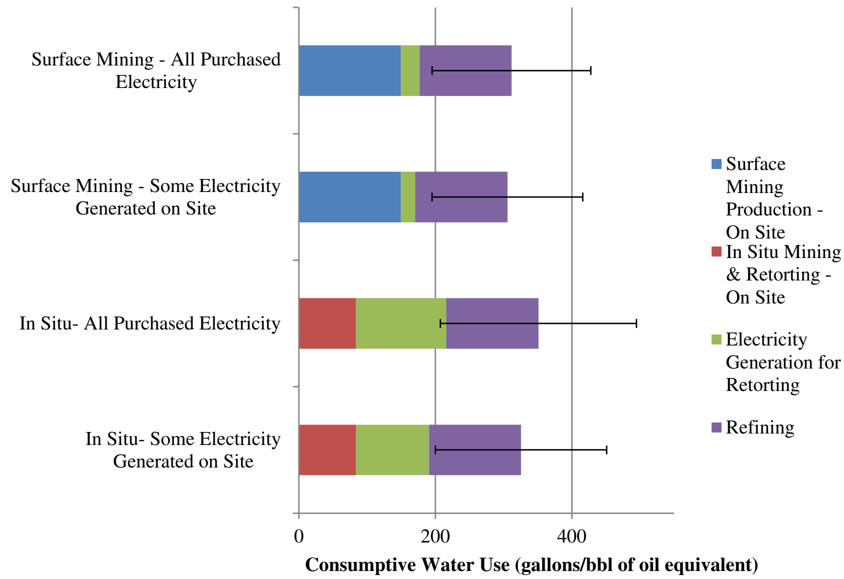


Fig. 3 Life cycle consumptive water use for oil shale production

The US Department of Energy suggests 2 million bpd of shale oil production is possible from the resources in Utah, Wyoming, and Colorado (Bartis et al. 2005; USGS 2013; Johnson et al. 2004). This is a significant level given that conventional production in 2011 was about 6 million bpd. At that 2 million bpd of production, and using the ranges of water requirements for production, retorting, disposal, electricity generation, and refining above, the consumptive water use would be significant: between 140 and 305 billion gallons (0.4 and 0.9 million acre-ft.) of water per year if surface mining and retorting, and between 150 and 340 billion gallons (0.5 and 1 million acre-ft.) of water per year if in situ processing. For comparison, DOE estimates that all 2005 thermoelectric power generation consumed 1,300 billion gallons (DOE 2009).

4 Discussion

4.1 Water supply issues in the oil shale region

Oil shale development requires significant amounts of water for extraction and processing. The largest US oil shale deposits are located in the Colorado River Basin, where water availability is a concern. The Colorado River Basin covers the area in seven US states (Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming). In 1922, the Colorado River Compact was signed (Norviel et al. 1922). Under this compact, two management areas were established for the USA: the upper river basin (parts of Arizona, Colorado, New Mexico, Utah, and Wyoming) and the lower river basin (Arizona, California, and Nevada). Lee's Ferry is the point in the main stream of the Colorado River at which the division occurs. Historic natural flows at Lee's Ferry were used to allocate the river water in perpetuity. Each basin was allocated 7.5 million acre-ft./year. In addition, Mexico is entitled to 1.5 million acre-ft./year, as established by the Mexican Water Treaty of 1944 (DOI 2009a, b). The Colorado River Compact of 1922 did not allocate water use to the states in the basin; this task became the responsibility of each of the two basin managers. The Upper Colorado Basin Compact of 1948 apportioned water rights to the states in the upper basin (DOI 2009a, b). The US Supreme Court, in settling a dispute between Arizona and California about their water rights, decided the allocation of the water rights for the states in the lower basin in the 1960s (DOI 2009a, b). The perpetual water allocation for each state in the Colorado River Basin are listed as follows: 4.4 million acre-ft./year for California, 3.9 million acre-ft./year for Colorado, 2.9 million acre-ft./year for Arizona, 1.7 million acre-ft./year for Utah, 1.5 million acre-ft./year for Mexico, 1.1 million acre-ft./year for Wyoming, 0.8 million acre-ft./year for New Mexico, and 0.3 million acre-ft./year for Nevada. Our results suggest that the consumptive water requirements for a 2 million bpd oil shale sector would be larger or roughly equivalent to the water allocated to Nevada, New Mexico, or Wyoming.

Since the treaty was established, however, water availability has varied dramatically from year to year. Figure 4 shows the five-year running average water available in excess of the treaties established throughout the twentieth century.

Figure 5 further shows water use (including water loss through evaporation and water deliveries to Mexico) from 1971 to 2007 (DOI 1991, 1998, 2002a, b, 2003, 2004, 2005a, b, c, d, 2006, 2007, 2008a, b, 2009a, b). While individual states may not be using their full allocation, they are selling their water rights to other states such that the US states are consuming all the water allocated to them by the Colorado River Compact and the Mexican Water Treaty. As population continues to grow in the region, demand for water will increase. At the same time, climate change could reduce water availability in the region (Christensen et al. 2004). Increased water demand for oil shale development would exacerbate regional water problems.

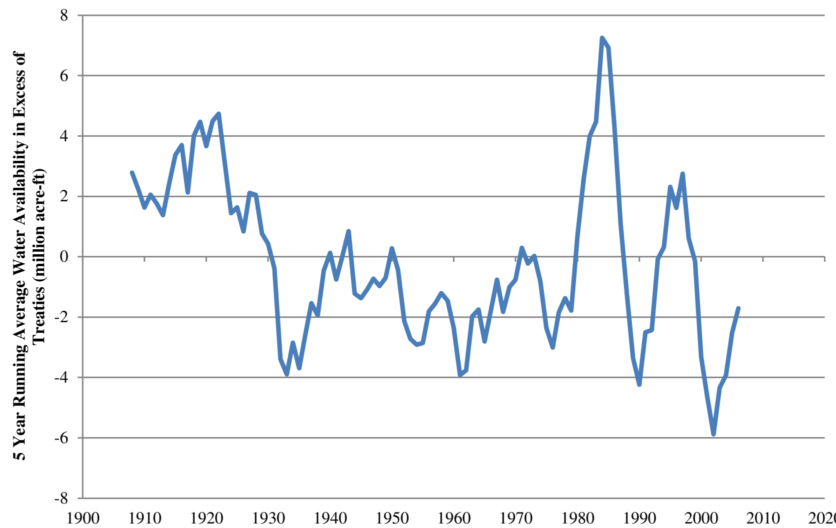


Fig. 4 Five-year running average excess water (adapted from DOI 2008a, b, c, d)

Water laws in the region are complicated and could result in legal disputes among energy companies and other consumers. Not only are the states trading water among each other but also allocation to individual consumers is based on seniority and "first in time, first in right." A study published in 2009 by Western Resource Advocates (WRA 2009) estimates that under the existing regulatory framework, energy companies water rights total 0.8 million acre-ft. per year. This volume of water is enough to meet the demand of a 2 million bpd project modeled here. However, the companies have not exercised their water rights, which has allowed other users access to the water. Given the complex water laws in the area, there is uncertainty as to whether these senior water rights will be honored. Court intervention is likely, and large and secure water supplies may thus be difficult and expensive to acquire, driving oil shale developers to seek alternative sources of water supply (DOE 2011).

4.2 Strategies for water supply certainty

Figure 3 showed the life cycle consumptive water use of oil shale production. The analysis assumed that all water would come from the oil shale region. However, given the uncertainty associated with water availability in the Colorado River Basin, this may not be the case. In this section, other potential approaches to providing water and alleviating the basin constraints are evaluated including refining the shale oil outside of the oil shale region (removing the need for local water), using dry cooling systems for electricity generation, and building desalination plants in California (to replace water consumed in the upper Colorado River Basin) are explored. A back-of-the-envelope calculation suggests that assuming RO will be used on site for treating 10 % of the water needed in the production process, on-site water needs could decrease by approximately 15 gals/bble for surface mining and 8.5 gals/bble for in situ production. However, energy requirements on site would increase by 0.35 kWh/bble for surface mining and 0.2 kWh/bble for in situ, and water related to increased electricity production (indirect water requirement) would be 0.13 gals of water/bble for surface mining and 0.08 gals of water/bble. For a large-scale production at 2 million barrels, the net reduction in local water associated with treatment and reuse would thus range between 6 and 10 billion gallons of water per year. The

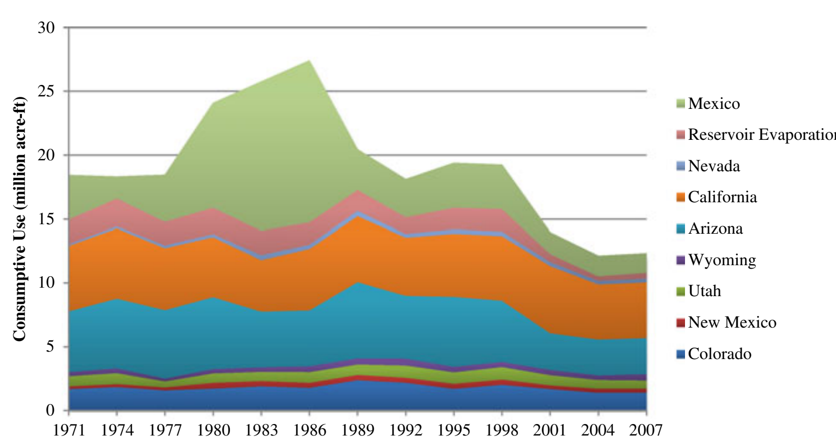


Fig. 5 Consumptive water use in the Colorado River Basin (adapted from DOI 1991, 1998, 2002a, 2002b, 2003, 2004, 2005a, 2005b, 2005c, 2005d, 2006, 2007, 2008a, 2008b, 2009a)

potential reduction in water needs associated with reuse of produced and wastewater is thus insufficient to alleviate water supply constraints.

As shown in Fig. 3, the refining stage of the life cycle requires significant amounts of water. If 2 million bpd of oil shale were produced, refining would require between 50 and 150 billion gallons of water per year (0.16 to 0.45 million acre-ft./year), depending on the refinery technology used. The government uses the Petroleum Administration for Defense Districts (PADD) to organize data collection and planning of crude oil supply and demand in the USA. The Rockies region, where the oil shale resources are located, is in PADD IV. Transporting oil shale to other PADDs would reduce the water pressure on the Colorado River Basin. Pipelines in PADD IV, however, currently have limited capacity and likely cannot accommodate inflows of large-scale production of shale oil. In general, the pipeline system in PADD IV serves to transport local production and imports from Canada to regional refineries and to the PADD II (Midwest). The two pipelines used to deliver crude oil from PADD IV to PADD II are the Enbridge and the Platte Pipelines. These pipelines have been operating at full capacity since 2005 and are creating a bottleneck to oil exports from PADD IV (Interstate Oil and Gas Compact Commission 2007). It is likely that new pipelines would need to be constructed.

The costs of building new pipeline capacity to “export” oil shale out of the region can be considered a cost of water supply certainty. There may be other reasons, besides water constraints, to build these pipelines such as investment costs of new refinery, approximately $2.5–14 billion (Gary et al. 2007; Sharma 2012). The costs allocated here to water supply certainty are thus a conservative estimate. Data from Federal Energy Regulatory Commission (FERC 2013) submitted by the oil pipeline industry (financial and operational information, including capital and operating costs) was used to estimate pipeline construction costs. Data for four existing trunk pipelines were used: Platte, Express, Enbridge, and Trans-mountain. These pipelines are located in Western USA and Canada. The data included expenditures on carrier property (Committee on Pipeline Planning of the Pipeline: Division of the American Society of Civil Engineers 1992), operating, and maintenance systems adjusted to 2006 dollars (National Aeronautics and Space Administration 2007). The average capital cost for a pipeline was estimated at 0.04–0.4 cents/bbl-mile. Building a pipeline to transport the crude 1,500 miles to Texas and the Gulf Coast region (or to the Great Lakes Region) would add, at most, $6 per barrel of shale oil. These additional costs may affect the cost of refined products derived from shale oil. According to Jaramillo et al., who used regression analysis to relate crude oil acquisition cost and cost of refined products, an increase of $6/bbl of crude oil would result in an increase of $0.25/gals of refined product (Jaramillo 2007).

Eliminating the need to provide refinery water from the Colorado River Basin reduces water use by 40 % for the 2 million barrel production level (consumptive water use from oil shale development could be reduced to 190–215 gals/bble for surface mining and retorting and 170–177 gals/bble for in situ production). Generating electricity via thermal power plants with dry cooling system could further reduce water consumption. A fossil thermal power plant with dry cooling system consumes 0.26–0.32 gals of water/kWh, an approximate reduction of 40 % in water consumption compared to Colorado's grid mix. There is an energy penalty associated with dry cooling systems, and the efficiency of the thermal plant is reduced to 34.6 % efficiency [compared to 36.1 % in a coal plant with a conventional wet cooling system (Berkenpas et al. 2004)]. In addition, the dry cooling system requires higher capital costs than once-through cooling. The incremental costs are $3.8 and $5.7/MWh for natural gas and coal-based power generation, respectively (Berkenpas et al. 2004). Based on the electricity consumption for the production of oil shale detailed in the previous section, the highest cost from using dry cooling would be $0.5 and $2.3/bbl for surface and in situ production, respectively. We assume that these would be the incremental cost of retrofitting current power plants in the region. In reality, new power plant may need to be built to meet the incremental electricity demand associated with oil shale production. The total costs of these new power plants, however, are not costs associated with reducing water needs and are not included.

If the electricity generated to meet the oil shale industry's energy requirements had dry cooling systems, consumptive water use from oil shale development could be reduced to 130–220 gals/bble for surface mining and retorting and 140–250 gals/bble for in situ production. Note that these numbers do not include the water needed for the refinery, as we assumed the oil would be exported to other PADDs (as described above). This would mean that 93–190 billion gallons of water per year (0.3–0.6 million acre-ft./year) would still be needed from the Colorado River Basin in order to produce oil shale. The lower number is equivalent to the total amount of water from the Colorado River Basin allocated to the state of Nevada by the Colorado River Compact, while the higher value approaches the amount of water allocated to the state of New Mexico.

Further reductions would require more radical approaches, such as developing desalination projects, which could potentially be built along the California coast in exchange for obtaining a portion of California's water rights in the Colorado River Basin. Reverse osmosis (RO) processes could be used to desalinate water on the California coast. The RO process has the lowest energy requirements and costs of all desalination technologies (Semiat 2008; Younos 2005). According to Semiat (2008), energy consumption for RO ranges between 11 and 22 kWh of electricity per thousand gallons of desalinated water. For the rest of the analysis, the higher energy consumption estimate is used as a bounding analysis. Table 1 shows the volume of water required to support 2 million bpd of oil shale industry. These estimates include the consumptive water use of production, retorting, disposal, and electricity generation for in situ or

surface mining oil shale production. As previously mentioned, we modified our original estimates from Fig. 2 by assuming that fossil-based thermal power plant with dry cooling is used to generate the electricity used for oil shale development. The estimates of the volume of water needed also include the consumptive water use associated with generating the electricity used for the desalination, assuming the electricity comes from natural gas-based power generation with dry cooling. These are found to be minimal compared to all the other water requirements. Note also that the water volumes that need to be desalinated also exclude refinery water.

Younos (2005) estimates cost ranges for desalination of seawater via RO between $2 and $25 per thousand gallons of desalinated water. The highest estimated cost and highest estimated volume to be desalinated for each extraction method (from Table 1) are used to calculate the costs associated with desalinating water to provide water supply certainty. Table 2 also provides the costs of the other strategies for water supply certainty described earlier in the paper.

A study by the Rand Corporation (Bartis et al. 2005) estimates that the initial cost of shale oil (mining and surface retorting) ranges between $70 and $95/bbl. Additional costs resulting from the strategies to manage water availability are described in Table 2. The highest estimate is used to calculate the costs of production and would bring total costs of productions as high as $110/bbl. In reality, these are not costs that will be directly added to the costs of oil. Instead, they show the costs that society must be willing to pay to develop oil shale resources without disrupting the water balance in the Colorado River Basin. Note that the costs estimated here are limited due to data availability. The cost data used here might be outdated as costs of novel technologies tend to decrease over time.

4.3 Greenhouse gas implications of water supply certainty

Brandt (2008, 2009) estimated life cycle greenhouse gas (GHG) emissions of oil shale production, including emissions from production, transport, refining, and combustion of the final products. These estimates also include the emissions associated with electricity consumed during the life cycle. Brandt assumed the Colorado electricity production mix: 72 % coal and 24 % natural gas, which is slightly higher than the current generation mix. The life cycle GHG emissions for surface mining and retorting were 1,740 and 2,060 lb CO_2e/bble for the low- and high-energy consumption scenario previously described, and for in situ oil shale production, 1,515 and 1,835 lb CO_2e/bble for the low and high scenarios. The addition of crude oil pipelines to transport the shale oil from the oil shale region to other regions is not expected to significantly impact these estimates since Brandt's numbers include emission from refining and transporting crude oil and refined petroleum products. Desalination plants are energy intensive, so the emissions are calculated for the desalination plants. Table 3 shows the GHG emissions associated with energy consumption for desalination, calculated using the natural gas-based power plant.

The highest emissions (7 lb CO_2e/bble for the high-energy scenario for shale oil produced by surface mining and retorting) do not significantly contribute to the overall life cycle GHG emission of shale oil. Even if the Colorado's electricity generation fuel mix is used in the calculations of Brandt (2008, 2009), the need for desalination plants adds at most 12 lb CO_2e/bble, less than 2 % of the life cycle GHG emissions of oil shale.

It is important to note that GHG emissions are a concern with shale oil production. Allocating the GHG emissions associated with operating the water infrastructure discussed in this paper to the shale oil produced does not affect the life cycle GHG emissions estimates for shale oil. These life cycle estimates for shale oil, however, are significantly higher than the life cycle GHG emission of conventional oil. All else

Table 1 Volume of water for desalination

Water supply strategy		Total water desalinated (million acre-ft./year)
Refinery outside the oil shale region and dry cooling for electricity generation	In situ	0.3–0.6
	Surface mining	0.3–0.5

Table 2 Upper-bound costs associated with strategies for water supply certainty (units in US dollar per barrel)

Water supply strategy	Refinery outside the oil shale region	
	In situ	Surface mining
Dry cooling	2.3	0.5
Oil pipeline	6	6
Desalination	6.4	5.5
Total costs of new infrastructure[a]	15	12

These costs do not include the costs from building new refineries. The costs of dry cooling are only incremental costs of the system, not the costs of building new power plants

[a] Totals may not add up due to rounding

Table 3 GHG emissions associated with water desalination

Oil shale production scenario	Emissions associated with desalination (lb CO_2e/bble)
In situ (low energy)	3.6
In situ (high energy)	6.6
Surface (low energy)	3.3
Surface (high energy)	5.7

being equal, meeting increasing demand for transportation energy with oil shale will undeniably result in increased GHG emissions from this sector.

5 Conclusions

Oil shale development in Colorado, Utah, and Wyoming could result in significant consumptive water use. These oil shale resources are located within the Colorado River Basin, where water availability is a concern. Current laws regarding water rights in the basin could allow energy companies to proceed with oil shale development, as these companies currently hold significant senior water rights. As development proceeds and the energy companies start using water, states in the lower basin and junior right holders, who have been using the water for the past decades, will face water constraints and may seek to alter the water agreements that have been in place since the 1920s.

Increased demand of water in the upper Colorado River Basin (where oil shale resources are located) could severely impact California, since California has the largest consumptive water use in the Colorado River Basin. Thus, the effects that oil shale development may have on the water supply for California (and other states in the Colorado River Basin) are of key importance. There are viable water management strategies to allow oil shale development while mitigating the effects to other water users. There are, however, costs to these strategies. Overall, the water supply strategies described in this paper could result in costs equivalent to a $15/bbl increase in the cost of producing shale oil. With this equivalent cost increase, the production cost of shale oil would reach $110/bbl, higher than the current crude oil prices. The Energy Information Administration, however, projects prices of imported low sulfur light crude oil to reach $110/bbl by 2020 and to increase to $130/bbl by 2035 (DOE 2010). Thus, if the social costs of water supply strategies were transferred to energy companies, shale oil produced at $110/bbl may in fact be competitive in the near future.

Water supply in the Colorado River Basin could be a primary constraint to the development of oil shale if equitable water use strategies are not identified. However, energy companies and governments in the region who hold rights to the water may not be fully considering the up and downstream implications of the consumptive water use of the technology. To ensure that the total use of water in the basin is managed properly, oil shale companies may need to be incentivized to consider the total life cycle externalities associated with increased water consumption. Water diverted to oil shale development could impact current economic activities and limit growth throughout the region. Thus, even if the current water right system allows energy companies to consume the water, the societal impacts on decreased water availability for the states in the Colorado River Basin need to be considered.

Acknowledgments This material is based upon work supported by the US National Science Foundation (grant number 0628084). Any opinions, findings, and conclusions expressed in this material are those of the authors and do not necessarily reflect the views of this organization.

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